

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PHASE II

UM 1610

In the Matter of)
)
PUBLIC UTILITY COMMISSION OF)
OREGON)
)
Investigation Into Qualifying Facility)
Contracting and Pricing.)

RESPONSE TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

July 24, 2015

1 **INTRODUCTION**

2 **Q. Please state your name and address.**

3 **A.** My name is John R. Lowe. I am the Executive Director of the Renewable Energy
4 Coalition (the “Coalition”). My business address is 12040 SW Tremont Street, Portland,
5 Oregon 97225.

6 **Q. Are you the same John Lowe who previously testified in Phase I and II of this**
7 **proceeding?**

8
9 **A.** Yes.

10 **Q. What issues do you address in Phase II?**

11 **A.** My testimony addresses all the remaining issues in Phase II of this investigation into
12 qualifying facility (“QF”) pricing and contracting. My Phase II testimony focuses on the
13 following issues:

- 14 • What is the appropriate forum to resolve disputed inputs and assumptions?
15
16 • What is the most appropriate methodology for calculating non-standard avoided
17 cost prices? Should the methodology be the same for all three electric utilities
18 operating in Oregon?
19
20 • When is there a legally enforceable obligation?
21
22 • Whether the market prices used during the resource sufficiency period sufficiently
23 compensate for capacity?
24
25 • How should third-party transmission costs to move QF output in a load pocket to
26 load be calculated and accounted for in the standard contract?
27

28 My testimony also reaffirms the Coalition’s position and/or supports the positions
29 of other parties on the following issues:

- 30
31 • Who owns the Green Tags during the last five years of a 20-year fixed price PPA
32 during which prices paid to the QF are at market?
33
34 • Should avoided transmission costs for non-renewable and renewable proxy
35 resources be included in the calculation of avoided cost prices?

- 1
- 2 • Should the capacity contribution calculation for the standard non-renewable
3 avoided cost prices be modified to mirror any change to the solar capacity
4 contribution calculation used to calculate the standard renewable avoided cost
5 price?
6

7 **Q. Before addressing each of the specific issues, do you have any overall comments?**

8 **A.** Yes. There has been an unprecedented number of filings and proceedings related to the
9 Public Utility Regulatory Policies Act (“PURPA”) in this and other states. The utilities
10 are attempting to take advantage of what may be a short-term and inflated amount of
11 solar QF development to dismantle PURPA. My testimony assumes that Idaho Power
12 and PacifiCorp’s proposals in UM 1725 and UM 1734 to change the contract term, and
13 reduce size thresholds are rejected. The Commission would need to revisit and revise
14 many of the issues under consideration in this proceeding if any aspect of Idaho Power’s
15 and PacifiCorp’s requests are approved.

16 **APPROPRIATE FORUM FOR DISPUTED AVOIDED COST INPUTS AND**
17 **ASSUMPTIONS**

18

19 **Q. Why is this issue important for the Coalition?**

20

21 **A.** The avoided cost inputs and assumptions determine the prices that QFs are paid for their
22 power sales to Oregon investor owned electric utilities. It is critically important for the
23 economic survival of QFs that these prices be accurately set so that they are appropriately
24 paid for all of the capacity and energy that they provide to the utilities. Similarly,
25 avoided cost rates need to be accurately set to ensure that ratepayers are held harmless
26 when a utility purchases power from a QF instead of building its own generation
27 resources. Given the importance of accurately setting the avoided cost rates, there should
28 be a forum for QFs, Staff, and other interested parties to address and challenge avoided
29 cost rate inputs and assumptions.

1 **Q. Please summarize the testimony of the parties you are responding to regarding this**
2 **issue.**

3
4 **A.** There are a variety of different proposals regarding how the inputs and assumptions
5 should be reviewed and approved. On one side are Staff, Oregon Department of Energy
6 (“ODOE”), the QF parties, and Portland General Electric Company (“PGE”) that believe
7 there needs to be an opportunity to review, challenge, and obtain Commission resolution
8 of avoided cost rate issues. These parties disagree about when and where avoided cost
9 rates should be addressed, but they all agree that they should be an opportunity to dispute
10 what inputs and assumptions the utilities decide to use. On the other side are PacifiCorp
11 and Idaho Power, which to greater or lesser degrees, believe that there are some issues
12 that Staff, QFs, and other interested parties should not have the ability to address or
13 challenge, at least before the avoided cost rates go into effect.

14 The parties positions on this issue are:

- 15 • Commission Staff: All inputs and assumptions should be reviewed in a
16 compliance filing after the annual update or Commission acknowledgement of a
17 utility’s integrated resource plan (“IRP”). Staff/500, Andrus/25-26.
18
- 19 • ODOE: All inputs and assumptions should be reviewed in a separate proceeding
20 that runs parallel with (meaning at the same time as) the utility’s IRP.
21 ODOE/700, Carver/5-6.
22
- 23 • Idaho Power: Certain inputs and assumptions should be reviewed in a separate
24 PURPA proceeding, and there should not be any substantive review in an IRP or
25 compliance filing. Assumptions and inputs that have never been reviewed by the
26 Commission should not be subject to challenge in a compliance filing, but
27 interested parties should be required to file a separate application, petition, or
28 other pleading to these challenge inputs or assumptions after avoided cost rates
29 change. Idaho Power/900, Allphin/4-6.
30
- 31 • PacifiCorp: Inputs and assumptions should be based on the utilities’
32 acknowledged IRP, but parties should not have the ability to challenge and obtain
33 a Commission decision on the reasonableness of any inputs or assumptions. The
34 utility and not the Commission ultimately sets the avoided cost rates. PAC/900,
35 Drennan/12.

- 1
- 2 • PGE: Inputs and assumptions should be based on the IRP; however, parties
- 3 should have the opportunity to challenge them in a subsequent proceeding. PGE
- 4 does not identify the standard upon which the Commission would rule on disputed
- 5 inputs and assumptions, including the importance of consistency or inconsistency
- 6 with the inputs and assumptions used in the IRP. PGE/500, MacFarlane-
- 7 Motion/8.
- 8
- 9 • Community Renewable Energy Association (“CREA”): Parties should be
- 10 provided an opportunity to review, challenge and obtain Commission resolution
- 11 on all inputs and assumptions before the avoided cost rates become effective.
- 12 CREA/500, Skeahan/14-15.
- 13
- 14 • REC: Parties should be provided an opportunity to review, challenge and obtain
- 15 Commission resolution on all inputs and assumptions before the avoided cost
- 16 rates become effective. A separate proceeding at the time of the IRP is preferable,
- 17 but an expanded post-filing compliance proceeding is also acceptable if properly
- 18 structured. Coalition/500, Lowe/16-17.
- 19

20 **Q. Are any of the proposals by the other parties acceptable?**

21 **A.** Yes. Staff and ODOE have made the most clear and specific proposals, both of which

22 could ultimately provide interested parties an opportunity to challenge the utilities’

23 avoided cost rates. They meet the essential requirement that parties be provided a forum

24 to raise their issues and obtain Commission resolution prior to the rates becoming

25 effective.

26 A general approach like ODOE’s that reviews the avoided cost rates in a separate

27 proceeding at the same time as the IRP is the best solution. ODOE’s recommendation

28 would reduce the possibility that there will be inconsistency between avoided cost rates

29 and the IRP. Even if there is no legal presumption of reasonableness, the Commission

30 may be reluctant to issue an order in avoided cost rate proceeding that is different from

31 what the utility included in an acknowledged IRP. Also, reviewing the avoided cost

32 inputs and assumptions in a separate proceeding would reduce the time needed to review

33 the actual avoided cost rate filings, which would result in more expeditious proceeding of

1 compliance filings.

2 Staff's approach is also acceptable, but the importance of the utility's
3 acknowledged IRP would need to be clarified. Staff's approach ensures that the utilities
4 have the burden of proof to demonstrate the reasonableness of the inputs and
5 assumptions, but does not explain the role of the inputs and assumptions used from an
6 acknowledged IRP. As I explained in my opening testimony, consistency with
7 specifically acknowledged part of the plan may be evidence in support of reasonableness
8 when approving the avoided cost rates, but it should not be a guarantee that the rates will
9 be approved. Consistency with the IRP should not be relevant for any aspect of the IRP
10 that was not specifically acknowledged by the Commission. Any party should be
11 allowed to challenge the utility's reliance on the acknowledged IRP, or the utility's
12 deviations from the most recently acknowledged IRP.

13 **Q. Are any of the proposals by the other parties unacceptable?**

14 **A.** Yes. PacifiCorp's recommendation that inputs and assumptions from the IRP should be
15 used, but that parties cannot review, challenge, or obtain a Commission order regarding
16 their reasonableness is unacceptable. PacifiCorp's position is essentially that it ultimately
17 has the unilateral choice to set avoided cost rates. This means that the Commission itself
18 would be taken out of the process of reviewing the inputs and assumptions.

19 PacifiCorp's position would be a departure from Commission precedent and any
20 reasonable public policy. The Coalition will also address in legal briefs whether
21 PacifiCorp's approach is consistent with the law. PacifiCorp's approach that it and only
22 it is the arbiter of avoided cost issues is an example of the utility's approach to many
23 PURPA matters, including contract negotiation and implementation. PacifiCorp often

1 takes extreme positions that puts QFs in the position of agreeing to unreasonable
2 demands, or being subject to harmful delays and/or expensive litigation.

3 Idaho Power's proposal that parties cannot challenge certain inputs and
4 assumptions before the avoided cost rates become effective also is unacceptable. Idaho
5 Power recommends that inputs and assumptions that have not been reviewed in a separate
6 PURPA proceeding cannot be challenged before the avoided cost rates become effective.
7 Idaho Power's proposal would require parties to file their own petition or application to
8 challenge the inputs and assumptions. While the avoided cost rates are being challenged,
9 the QFs would need to make sales at potentially illegal prices. Avoided cost rate inputs
10 and assumptions should never go into effect without Staff and interested parties having
11 the ability to raise their concerns and obtain a Commission order on all disputed issues.

12 **Q. REC recommends that minimum filing requirements be used. Do other parties**
13 **address the issue of minimum filing requirements?**

14 **A.** Yes. Staff also requests that the Commission require the utilities to include minimum
15 filing requirements, and PGE states that it will provide citations to its IRP with its
16 avoided cost rate filing. The information requested in Staff's minimum filing
17 requirements is generally acceptable, and should be the minimum information provided
18 with the utility's avoided cost rate filings. PGE's proposal to reference its IRP is
19 welcome and appreciated because it can be difficult identify where specific inputs and
20 assumptions came from. I also have been made aware that PGE generally provides well
21 supported and detailed information in its power cost rate proceedings. PGE's proposal,
22 however, is insufficient because the IRP is not the only source of information for avoided
23 cost rate inputs and assumptions. In addition, simple citations may not provide sufficient
24 information to understand the basis for the input or assumption. Therefore, the minimum
25

1 filing requirements attached to my opening testimony and/or Staff's should be used.

2 **CAPACITY VALUE DURING THE RESOURCE SUFFICIENCY PERIOD**

3
4 **Q. Do the resource sufficiency prices adequately compensate QFs for the capacity value**
5 **they provide to the utilities and ratepayers?**

6 **A.** No. Kevin Higgins addressed this issue for the Coalition and other QF parties in opening
7 testimony. The utilities and Commission Staff propose to maintain the current avoided
8 cost rate methodology that only pays QFs the value of market purchases, rather than the
9 full capacity value that QFs provide to the utilities and ratepayers. For example,
10 PacifiCorp witness Brian Dickman supports setting resource sufficiency prices solely on
11 market purchases. PAC/800, Dickman/14-16.

12 **Q. Do you agree with Mr. Dickman that PacifiCorp will only rely upon market**
13 **purchases for its capacity needs during the sufficiency period identified in its IRP?**

14 **A.** No. As explained in the Coalition's opening testimony, PacifiCorp will also be relying
15 upon QFs to provide capacity, and will be making expensive investments in retaining its
16 existing thermal plant capacity. For example, PacifiCorp is currently planning on the
17 availability of 255 MWs of QFs to meet its system peak. PacifiCorp 2015 IRP at 62.
18 These QFs have been causing, and those that renew their contracts will continue to cause,
19 PacifiCorp to avoid capacity costs. Not paying capacity to these existing QFs contributes
20 to the risk of more capacity being needed if projects do enter into new PPAs following
21 the expiration of their current contracts.

22 PacifiCorp's approach also fails to recognize that its current IRP plans to acquire
23 a new combined cycle combustion turbine in 2027 or 2028 is likely to be inaccurate
24 (2013 IRP Update and 2015 IRP). PacifiCorp's planned resource acquisitions have
25 historically been inaccurate, especially during the longer-term. For example, in 2008

1 PacifiCorp did not “plan” on acquiring a new thermal resource until 2012. However,
2 PacifiCorp acquired the 520 MW Chehalis plant in 2008. PacifiCorp’s resource needs
3 identified in its current IRPs may be even more inaccurate. PacifiCorp’s actual resource
4 acquisitions could significantly change if its IRP assumptions prove inaccurate, including
5 but not limited to: 1) changes in Washington’s or Oregon’s renewable portfolio standard
6 (“RPS”); 2) PacifiCorp joining the California Independent System Operator; 3) the
7 adoption of a federal RPS; 4) adoption of a state or federal carbon tax; 5) the adoption of
8 EPA’s Section 111(d) rules; 6) closure of part or all of coal generation facilities; 7) the
9 inability to capture the high levels of demand side management; and 8) the lack of
10 availability of power in the wholesale market. Most of these policies could result in a
11 reduction in coal generation, and an increase in renewables, baseload gas, and peaking
12 gas generation well before 2027. Therefore, PacifiCorp is likely to acquire significant
13 capacity resources during its alleged resource sufficiency period.

14 **Q. Has PacifiCorp raised similar arguments in other states?**

15
16 **A.** Yes. PacifiCorp has made similar proposals to regarding resource sufficiency prices in
17 many of the states that the company operates. For example, PacifiCorp’s avoided cost
18 rates in Washington currently include a kilowatt hour energy rate and a kilowatt month
19 capacity payment. On behalf of PacifiCorp, Mr. Dickman is proposing to eliminate the
20 kilowatt month capacity payment, and only pay QFs energy rates in Washington.

21 The Washington Utilities and Transportation Commission (“Washington
22 Commission”) staff strongly opposes PacifiCorp’s proposal. The Washington
23 Commission Staff points out that during the resource “sufficiency” period as defined by
24 PacifiCorp, the company is in fact capacity deficit and will acquire capacity. The

1 Washington Commission Staff also recognizes that PacifiCorp plans on existing QFs
2 renewing their contracts and providing capacity that they are not compensated for.
3 Relying upon information provided by the Northwest Power and Conservation Council,
4 the Washington Commission Staff also criticizes PacifiCorp for reliance upon the
5 wholesale power market. The Washington Commission Staff notes that the Northwest
6 Power and Conservation Council proposes a market premium risk adjustment for valuing
7 conservation resources because of concerns regarding the resources available in the
8 wholesale market. Ultimately, the Washington Commission Staff proposes that capacity
9 during the alleged resource sufficiency years should be based on Washington's
10 methodology for valuing incremental capacity for the purposes of the Washington RPS
11 reporting. The Washington Commission Staff proposes a \$4.58 kilowatt month capacity
12 payment, which is an increase from the current about \$2.50 Washington kilowatt month
13 capacity payment. This proposal results in a larger capacity payment than Kevin Higgins
14 has recommended in this proceeding.

15 **THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING NON-**
16 **STANDARD AVOIDED COST PRICES**

17
18 **Q. Why is this issue important for the Coalition?**

19 **A.** The Coalition believes that the avoided cost rates for all QFs, including those above 10
20 MWs that must negotiate their rates, be just and reasonable for both the utility and the
21 QF.

22 **Q. What are the positions of the other parties on this issue?**

23 **A.** Staff and the utilities recommend that each utility be allowed to select an their own
24 methodology to set negotiated avoided cost rates. Therefore, PGE would continue to use
25 the current Commission approved process for negotiating avoided cost rates that starts

1 with the utility's approved rates for smaller QFs and adjusts them using specific
2 Commission-approved factors. PacifiCorp and Idaho Power, however, would be able to
3 use their own computer models to calculate large QF avoided cost rates. Staff supports
4 this approach on the grounds that the utilities' power cost models have been successfully
5 used in rate cases. PacifiCorp supports this approach because it will be able to use the
6 computer modeling approach set the avoided cost rates will be lower than the current
7 Commission-approved approach. Idaho Power supports this approach because it is what
8 is used in its Idaho jurisdiction.

9 **Q. Do you agree with PacifiCorp?**

10 **A.** No. As explained in my testimony in both Phase I and II, and Don Schoenbeck's
11 testimony in Phase I, PacifiCorp should not be allowed to use its computer model to set
12 avoided cost rates for large QFs. PacifiCorp's proposal will not result in more accurate
13 avoided cost rates, but will instead increase costs (and a variety of other problems
14 including potential complaints) during an already difficult and complex negotiating
15 process.

16 This responsive testimony only addresses new issues identified by PacifiCorp in
17 Phase II. For example, Mr. Schoenbeck's earlier testimony refutes PacifiCorp's biased
18 and inaccurate comparison of the differences in standard avoided cost prices and its
19 computer model. The fact that experts cannot even reach agreement regarding how the
20 computer model would adjust avoided cost rates in an investigation that has lasted for
21 years demonstrates how difficult using the computer model can be. Adopting
22 PacifiCorp's approach will result in QFs either simply accepting inaccurate avoided cost
23 rates, or expending considerable resources investigating and challenging PacifiCorp's

1 decision and assumptions.

2 As previously explained in testimony, the Federal Energy Regulatory
3 Commission (“FERC”) has identified seven factors that may be taken into account when
4 setting avoided cost rates, and the Commission adopted a method to account for these
5 factors in Order No. 07-360. Negotiated rates for large QFs start with the standard
6 avoided cost rates for smaller QFs, with adjustments based on Commission approved
7 methodologies or contract provisions to account for these factors. PacifiCorp disagrees
8 with this approach, and wants to use its power cost model to estimate the value of these
9 seven factors and other potential adjustments. The justifications provided by Staff
10 witness Lisa Schwartz and adopted by the Commission in Order No. 07-360 to not use a
11 computer model are even more relevant today when PacifiCorp is doing everything in its
12 power to legislatively repeal or administratively neuter PURPA.

13 **Q. PacifiCorp states that it should be allowed to make adjustments related to issues not**
14 **on FERC’s list of seven factors. PAC/800, Dickman/21. Do you agree?**

15
16 **A.** No. First, in UM 1129 when the Commission adopted its current approach, Staff’s legal
17 position was that the seven factors identified by FERC was an all inclusive list and that
18 other factors could not be taken into account. E.g., Staff’s Opening Brief Phase II, Track
19 II at 15. Second, allowing PacifiCorp the opportunity to create new factors to lower
20 avoided cost prices without the Commission’s review and approval of how those factors
21 will impact avoided cost rates simply provides the company with too much discretion.

22 **Q. PacifiCorp states that only two of the seven FERC factors are accounted for.**
23 **PAC/800, Dickman/20-21. Do you agree?**

24
25 **A.** No. Order No. 07-360 addresses most of these factors through modeling adjustments or
26 contract provisions. The only two factors not accounted for by Order No. 07-360 are: 1)

1 the individual and aggregate value of energy and capacity from qualifying facilities on
2 the electric utility's system; and 2) the smaller capacity increments and the shorter lead
3 times available with additions of capacity from qualifying facilities. Both of these factors
4 should increase rather than decrease avoided cost rates, and the Commission allowed the
5 QF and utility to account for these factors if they could agree upon a practical and
6 reasonable way.

7 **Q. PacifiCorp states that it should be allowed to use as current as possible information**
8 **to update whatever inputs and assumptions it desires when using the computer**
9 **modeling approach, including inclusion of proposed QF PPAs. PAC/800,**
10 **Dickman/23-26. Do you agree?**

11
12 **A.** No. The same reasons for allowing limited annual updates support requiring PacifiCorp
13 to only use Commission-approved or acknowledged inputs and assumptions, plus the
14 limited set of factors (gas and market prices forecasts, and updated information about the
15 production tax credit). Annual updates, plus a potential additional update after
16 acknowledgement of an IRP allows frequent avoided cost rate changes. Annual updates
17 also ensure that parties have an opportunity to review and the Commission an opportunity
18 to approve the inputs and assumptions used in setting avoided cost rates. Similar policies
19 should apply to setting large QF avoided cost rates, regardless of whether they are part of
20 a computer model or the Commission's current approach.

21 Parties and the Commission will not have the ability to independently review
22 unproven changes, inputs, and assumptions, including whether the company's forecast of
23 proposed QF PPAs is reasonable. Referencing testimony in its UM 1734 filing,
24 PacifiCorp justifies updating for proposed QF PPA because it has received a large
25 number of new solar QF PPA requests and has entered into a large number of QF
26 contracts. PAC/800, Dickman/23-26. In UM 1734, Obsidian Renewables witness David

1 Brown demonstrated that few QFs that request PPAs or even enter into PPAs actually are
2 constructed. Mr. Brown's specific numbers match my experience in that the attrition
3 between QF contract or pricing requests and operational projects under contract is
4 extremely high. Therefore, PacifiCorp should not be allowed to reduce avoided cost rates
5 based on inflated numbers of possible QFs that are unlikely to ever generate electricity.
6 This is an example of, if allowed to use its computer model, PacifiCorp will creatively
7 attempt to think up new factors that will result in lower avoided cost rates below its actual
8 avoided costs.

9 **Q. Do you agree with Staff on allowing PacifiCorp to use its computer model?**

10
11 **A.** No. Staff supports allowing PacifiCorp to use a computer modeling approach because it
12 could be more accurate, and that PacifiCorp's computer model has been reviewed and
13 vetted in rate cases. Staff/500, Andrus/34-35. This is a change in Staff's position,
14 because in UM 1129 Staff recommended that each avoided cost rate adjustment factor be
15 specifically identified using a Commission-approved methodology to facilitate and
16 prevent abuse in the negotiation process.

17 While I am not an expert in computer models, Staff's reference to the use of
18 computer models in utility rate cases supports continuation of the current approach and
19 not using those models to set avoided cost rates. First, PacifiCorp's computer model was
20 designed to estimate power costs, and not set avoided cost rates for a specific project.
21 Second, PacifiCorp's computer model has been subject to frequent litigation with
22 modeling adjustments proposed by Staff and intervenors. Intervenors have retained
23 (sometimes with intervenor funding) expensive experts to review and analyze the
24 computer model. PacifiCorp has only two large QFs above 10 MWs in Oregon, and the

1 risk of potentially inaccurate avoided cost rates does not warrant the additional expense
2 and controversy in the avoided cost negotiation process.

3 **Q. Do you agree with Idaho Power on this issue?**

4 **A.** I do not oppose allowing Idaho Power to use the approach that it currently uses in Idaho.
5 The Commission has at times treated Idaho Power differently from PacifiCorp and PGE
6 because its Oregon operations are a small portion of its overall service territory.
7 Specifically, the Commission previously allowed Idaho Power to use its own computer
8 model to set large QF avoided cost rates and in UM 1129 the Commission held that
9 “Idaho Power, however, may use the modeling methodology approved by the Idaho
10 Public Utilities Commission for deriving avoided costs that serve as the starting point for
11 negotiations with large QFs under a legally enforceable obligation.” Order No 07-360 at
12 13. In addition, Idaho Power does not have any QFs above the current size threshold for
13 standard contracts and rates, so this issue may be purely academic as it relates to Idaho
14 Power (assuming the Commission rejects Idaho Power’s request to lower the size
15 threshold for wind and solar in UM 1725). If the Idaho Public Utilities Commission,
16 however, approves changes in the company’s current modeling approach, Idaho Power
17 should be required to obtain approval to use the new model in Oregon. The Commission
18 should not delegate complete responsibility for the methodology for setting large QF
19 avoided cost rates to another regulatory body.

20 **WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?**

21
22 **Q. Why is this an important issue for the Coalition?**

23 **A.** With annual avoided cost filings this issue is may be even more significant than when
24 there were fewer avoided cost fillings. With annual filings there simply is no time for

1 delays in the contracting process without potentially subjecting a proposed project to
2 superseded and often lower prices.

3 Since utilities often delay the negotiation process, request unreasonable
4 information, or impose unduly burdensome requirements they can use this shorter filing
5 cycle in conjunction with uncertainty over when a legally enforceable obligation is
6 created to their advantage. The utilities can also be openly hostile to QF development
7 because they do not earn a return on power purchases from third parties. Small QFs are
8 often taken advantage of because they rarely negotiate these types of contracts, and have
9 limited knowledge of PURPA, avoided cost matters, and power markets. The
10 Commission needs to ensure that there are fair and balanced policies to protect QFs, and
11 the right of a QF to legally obligate itself to sell power at then current avoided cost rates
12 is a necessary tool to prevent utility abuses.

13 My previous testimony in Phase I and II, and Don Schoenbeck's testimony in
14 Phase I addressed this issue and has rebutted most of the arguments raised by the utilities
15 in Phase II. Essentially, the utilities want to continue to have the right to delay the
16 negotiation process without allowing QFs to enter into a legally enforceable obligation.
17 This testimony responds to new arguments raised by Idaho Power and Staff.

18 **Q. Idaho Power proposes that a QF cannot legally obligate itself unless it can deliver**
19 **the power in 365 days. Idaho Power/900, Allphin/9. Do you agree?**

20
21 **A.** Absolutely not. This is a thinly veiled proposal to prevent most QFs from entering into a
22 legally enforceable obligation. Both new and existing QFs often need to upgrade and
23 invest in interconnection and/or network upgrades to be able to sell their electricity. The
24 interconnection process can take well over a year. For example, PacifiCorp recommends
25 that a QF plan on at least a year and a half to complete the process. Delays can cause the

1 process to last even longer. QFs often must first enter into a PPA to obtain financing for
2 both the interconnection and facility construction. This means that the end of the
3 interconnection process and actual commercial operation date is not known until after the
4 PPA is signed. Therefore, the QF may not know if it can, or be physically able to deliver
5 power, in one year when it is ready to legally obligate itself to sell power. Essentially,
6 Idaho Power is proposing a condition precedent to obtaining a legally enforceable
7 obligation that is simply impossible for many QFs to meet.

8 I agree, however, that there should be some limitation on when a QF can enter
9 into a legally enforceable obligation. Earlier in Phase II of this proceeding, the active
10 parties agreed that a QF should have a reasonable amount of time before contract
11 execution and commercial operation date. The parties agreed that QFs should have the
12 right to select a period of up to three years, with the possibility of additional time. In the
13 brief in support of the stipulation, Staff explained that allowing too little time between
14 contract execution and delivery can create a barrier for QFs because they “generally
15 cannot obtain financing for a new project until after they have executed a PPA. This
16 means that QFs must wait for execution of a standard contract before commencing many
17 of the steps that are necessary to bring a resource on line.” Brief in Support of
18 Stipulation at 3. This also applies to existing projects, especially those that need to re-
19 invest in interconnection and generation technology. In this situation I see no substantive
20 difference between a legally enforceable obligation and a contract execution, and a QF
21 should be to commit itself via a contract or legally enforceable obligation three years
22 before power deliveries are scheduled to occur, and potentially longer under unique
23 circumstances.

1 **Q. Staff proposes that a legally enforceable obligation can be entered into if a utility**
2 **does not meet all deadlines in the contract negotiation process. Staff/500,**
3 **Andrus/41. Do you agree?**

4
5 **A.** Yes. Staff's recommendation that a QF can show it has legally obligated itself if the
6 utility has not meet all the deadlines is reasonable and consistent with my
7 recommendation. Staff's proposal also requires the QF to provide the information
8 required by the utility's tariff or standard form contract. While not entirely clear, I
9 interpret this as allowing the QF to create a legally enforceable obligation if the utility
10 requests information, or proposes contract changes that are unreasonable. Therefore, I
11 believe Staff and the Coalition's positions to be substantially the same.

12 **HOW SHOULD THIRD-PARTY TRANSMISSION COSTS TO MOVE QF OUTPUT IN**
13 **A LOAD POCKET BE CALCULATED AND ACCOUNTED FOR?**
14

15 **Q. Why is this issue important for the Coalition?**

16 **A.** The Commission has ruled that QFs should be responsible for third party transmission
17 costs to move a QF's net output from a load pocket to the utility's load. While I agree
18 that a QF should pay these costs, there is a wide variety of options to move this power
19 and the QF should be allowed to select the type of transmission, as long as it reliably
20 meet's the QF's contractual obligations. In addition, existing QFs that have been selling
21 power to the utility, and that the utility has planned on their continued operations should
22 not be required to pay for third party transmission costs that are incurred for reasons
23 beyond the QF's control.

24 The issue primarily impacts PacifiCorp, and PacifiCorp's testimony on this issue
25 is very disappointing in the paucity of information provided. The Commission directed
26 the parties to propose a method "to calculate and assign the third-party transmission costs
27 that are attributable to the QF." Order No. 14-058 at 22. PacifiCorp, however, focused

1 its testimony on discussing why the QF should pay for third party transmission costs and
2 explaining its practices. Although it is not entirely clear, PacifiCorp appears to want to
3 require QFs to use only the most expensive option for obtaining third party transmission
4 costs: long term firm point to point transmission (“LTF PTP”). In addition, PacifiCorp
5 ignored the issue of third party transmission and costs for existing QFs when entering
6 into a replacement PPA, a key issue for the Coalition. The CREA was the only party that
7 made specific and concrete proposals on this issue, and I largely agree with their
8 recommendations. I also respond to broad points raised by the ODOE and the
9 Commission Staff on this issue.

10 **Q. Do you agree that PacifiCorp should always purchase LTF PTP to transmit a QF’s**
11 **net output to load?**

12 **A.** No. PacifiCorp admits that there are more cost effective options for QFs. PAC/1000,
13 Griswold/26. Load pocket issues may only occur during certain times of the year, and
14 there is no need to require a QF to pay for expensive transmission for the entire year to
15 only address a limited and discrete problem. This could include a use of facilities
16 agreement with Bonneville Power Administration, and/or conditional or short term firm
17 transmission. Alternatively, a QF should be able to agree to limited curtailment of power
18 deliveries for those few events in which generation exceeds load in the load pocket. A
19 QF should have the option of using LTF PTP, but not required to do so when other
20 alternatives are available. These recommendations are consistent with those presented by
21 CREA and ODOE. CREA/500, Skeahan/23-24; ODOE/800, Broad/12.

22 **Q. Do you agree that the costs of third party transmission should be set at the time the**
23 **PPA is entered into?**

24 **A.** No. PacifiCorp appears to be proposing that the specific allocation of third party
25

1 transmission costs should be resolved at the time of contract execution. PAC/1000,
2 Griswold/21-22. The existence and amount third party transmission costs, and options to
3 address the need to transmit the power, may not be known or capable of calculation until
4 after interconnection and transmission studies have been completed and negotiations with
5 third party transmission owners entered into. Therefore, the standard contract should
6 require the QF to pay for third party transmission costs, but provide the QF with the
7 option to select the specific method after the costs and need for third party transmission
8 are determined.

9 **Q. Does Staff address the load pocket issue?**

10 **A.** Only briefly. Staff appears to be planning on reviewing the specific proposals by the
11 parties and making a recommendation or proposal later in the case. Staff/500, Andrus/42.
12 Staff, however, recommends that the utility be required to provide specific and detailed
13 information regarding the load, generation, and transmission capacity values used, and
14 the basis for calculating the amount and cost of third party transmission. Id. CREA also
15 proposes specific informational needs and requirements by PacifiCorp to provide
16 information to QFs. CREA/500, Skeahan/21-22. I agree with these recommendations,
17 and they should be expanded. The utility should be required to provide this information
18 not only in the contract negotiation process, but also during the contract implementation
19 process. Disputes may occur after contracts are signed, and the QFs should have the right
20 to verify the need and costs of any third party transmission acquired (or that may be
21 acquired) on its behalf.

22 **Q. Do you agree with ODOE's recommendation that load pocket costs be updated as**
23 **changes occur? ODOE/800, Broad/17-21.**

24 **A.** Only if it is an option. A QF should be able to agree to short term arrangements that are

1 updated as third party transmission costs increase or decrease. Some QFs, however,
2 desire certainty or need know their costs in order to obtain financing, and should have the
3 right to enter into long-term contracts with a reasonable estimate of expected third party
4 transmission costs. In addition, the issues related to the dynamic changes to the existence
5 of a load pocket remain unaddressed. Load additions or reductions as well as generation
6 addition or reductions impact on party obligations, processes, and notices could create
7 significant problems.

8 **OTHER ISSUES**

9
10 **Q. Do you have a position on the remaining issues in the case?**

11 **A.** Yes. The remaining issues in the case include who owns the Green Tags, avoided
12 transmission costs for the proxy resource, and capacity contributions. As explained in
13 my opening testimony, the QF should own Green Tags during the last five years of a PPA
14 in which the QF is only paid market prices. In addition, the Coalition supports the
15 positions of Staff and the QFs on the issue of capacity contributions, and the position of
16 other QFs on the issue of avoided transmission costs for proxy resources. These issues
17 have been adequately developed in the testimony of other parties, and there is no need for
18 additional responsive testimony on behalf of the Coalition on these issues.

19 **CONCLUSION**

20 **Q. Does this conclude your testimony?**

21 **A.** Yes.